UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region8

Ref: 8WD-SDU

SENT VIA EMAIL
DIGITAL READ RECEIPT REQUESTED

Michelle Yalung
Michelle.Yalung@meritenergy.com

Re: Draft Permit - WY22427-12116, Brinkerhoff 3A

Dear Ms. Yalung:

Enclosed is a copy of the draft U.S. Environmental Protection Agency Region 8 Underground Injection Control (UIC) permit (Permit) for the above referenced well or project area. Also enclosed are copies of the statement of basis for the proposed action and the public notice provided on EPA's website at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy.

EPA regulations and procedures for issuing UIC permit decisions are found in Title 40 of the Code of Federal Regulations (40 CFR) part 124. These regulations and procedures require a public notice and the opportunity for the public to comment on this proposed Permit decision. The public comment period will run for at least 30 days and a courtesy announcement, also enclosed, has been published in the following newspaper(s):

Casper Star-Tribune
Riverton Ranger

A final decision will not be made until after the close of the comment period. All relevant comments will be taken into consideration. If any substantial comments are received, the effective date of the final Permit will be delayed for an additional 30 days, as required by 40 CFR § 124.15(b), to allow for any potential appeal of the final Permit decision.

If you have any questions or comments about the above action, please contact Chris Brown at (303) 312-6669 or Brown.Christopher.T@epa.gov.

Sincerely,

12/27/2021

X Douglas Minter

Signed by: DOUGLAS MINTER

Douglas Minter
Acting Chief, Safe Drinking Water Branch
Water Division

Enclosures

cc: Jordan Dresser, Chairman, jordan.dresser@northernarapaho.com
Northern Arapahoe Business Council

John St. Clair, Chairman, jstclair@easternshoshone.org
Eastern Shoshone Business Council

Brett Stavin, Attorney, bstavin@rosettelaw.com
Rosette, LLP

Steven Siros, Attorney, ssiros@jenner.com
Jenner & Block

Gordan Zane, Fluid Minerals Branch Chief, zane.gordon@bia.gov
U.S. Department of Interior, Bureau of Indian Affairs

John Elliott, Manager, Lander Field Office, j75ellio@blm.gov
U.S. Department of Interior, Bureau of Land Management

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PROGRAM

DRAFT PERMIT

WY22427-12116

Class II Enhanced Oil Recovery Well

Brinkerhoff 3A
Wind River Indian Reservation

Issued To

Merit Energy Company
13727 Noel Road, Suite 1200
Dallas, Texas 75240

TABLE OF CONTENTS.

PART I. AUTHORIZATION TO CONSTRUCT AND OPERATE

Under the authority of the Safe Drinking Water Act (SDWA) and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) parts 2, 124, 144, 146, and 147, and according to the terms of this permit (Permit),

Merit Energy Company
13727 Noel Road, Suite 1200
Dallas, Texas 75240

hereinafter referred to as the "Permittee," is authorized to convert and to operate the following Class II well:

Brinkerhoff 3A
330' FSL & 660' FEL, Section 9, Township 3N, Range 1W
Wind River Indian Reservation, Wyoming
49-013-06977

This Permit is based on representations made by the applicant and on other information contained in the administrative record. Misrepresentation of information or failure to fully disclose all relevant information may be cause for termination, revocation and reissuance, or modification of this Permit and/or formal enforcement action. It is the Permittee's responsibility to read and understand all provisions of this Permit.

Where a state or tribe is not authorized to administer the UIC program under the SDWA, EPA regulates underground injection of fluids into wells so that injection does not endanger Underground Sources of Drinking Water (USDWs). EPA UIC permit conditions are based on authorities set forth at 40 CFR parts 144 and 146 and address potential impacts to USDWs. Under 40 CFR part 144, subpart D, certain conditions apply to all UIC permits and may be incorporated either expressly or by reference. Regulations specific to Indian country injection wells in Wyoming are found at 40 CFR § 147.2553.

The Permittee is authorized to engage in underground injection in accordance with the conditions of this Permit. Any underground injection activity not authorized by this Permit or by rule is prohibited.

Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the SDWA or any other law governing protection of public health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations. Nothing in this Permit relieves the Permittee of any duties under applicable regulations.

This Permit is issued for the operating life of the facility or until it expires under the terms of the Permit, unless modified, revoked and reissued, or terminated under 40 CFR §§ 124.5, 144.12, 144.39, 144.40 or 144.41, and shall be reviewed at least once every five (5) years to determine if action is required under 40 CFR § 144.36(a).

Issue Date: ____________________ Effective Date ____________________

DRAFT

____

Angelique D. Diaz, Ph.D., P.E., Acting Chief*
Safe Drinking Water Branch
Water Division

* Throughout this Permit the term "Director" refers to the Safe Drinking Water Branch Chief or the Water Enforcement Branch Chief.

PART II. SPECIFIC PERMIT CONDITIONS

Section A. WELL CONSTRUCTION REQUIREMENTS

These requirements specify the approved minimum construction standards for well casing and cement, injection tubing, and packer.

The EPA-approved well construction plan is incorporated into this Permit as APPENDIX A. Changes to the approved construction plan prior to authorization to inject must be approved through permit modification by the Director, prior to being physically incorporated.

1. Casing and Cement

The well or wells shall be cased and cemented to prevent the movement of fluids into or between USDWs and shall be in accordance with 40 CFR § 146.22. Remedial construction measures may be required if the well is unable to demonstrate mechanical integrity or to prevent movement of fluids into or between USDWs.

2. Injection Tubing and Packer

Injection tubing is required and shall be run and set with a packer. The packer setting depth may be changed, provided the well construction requirements in APPENDIX A are met and the Permittee provides notice and obtains the Director's approval for the change.

3. Sampling and Monitoring Devices

The Permittee shall install and maintain in good operating condition:

(a) a pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure (MAIP) is reached at the wellhead;

(b) one-half (1/2) inch female iron pipe fitting, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the MAIP described in Part II, Section B.4:

- (i) on the injection tubing string(s);
- (ii) on the tubing-casing annulus (TCA); and
- (iii) on the surface casing-production casing (bradenhead) annulus;

(c) a sampling port such that samples shall be collected at a location that ensures they are representative of the injected fluid; and

(d) a flow meter capable of recording instantaneous flow rate and cumulative volume attached to the injection line.

4. Pre-Injection Well Logging and Testing

Well logging and testing requirements prior to receiving authorization to inject are found in APPENDIX B. Well logs and tests shall be performed according to current EPA-approved procedures, or alternate procedures approved by the Director. The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation. Limited injection is permissible prior to receiving authorization to inject only for the purposes of conducting the initial well logs and tests required in APPENDIX B.

5. Postponement of Construction or Conversion to Injection Wells

(a) For wells to be newly drilled, the Permit shall expire if well construction has not begun within two years of the Effective Date of the Permit.

(b) The Permittee may request a one-time extension of the permit expiration date, not to exceed two additional years, which must be made prior to expiration of the Permit. Notification shall be in writing and state the reasons for the delay, provide an estimated completion date, and list additional wells within the area of review (AOR) that were not included in the initial permit application. For those newly completed AOR wells that penetrate the confining zone, a well construction diagram, cement records and cement bond logs are also required.

Once the Permit has expired under this part, the Permittee will need to reapply for a UIC permit and restart the complete permit process, including opportunity for public comment, before injection can occur.

(c) For wells that have begun construction or are conversions to an injection well, if authorization to inject has not been provided within two years of spud date or the Effective Date of the Permit, respectively, the Permittee is subject to the conditions found in Part II, Section E.5. *Wells Not Actively Injecting* or may elect to convert the well to a non-UIC well found in Part III, Section A.2 *Conversion to Non-UIC Well.*

Section B. WELL OPERATION

1. Outermost Casing Injection Prohibition

Injection between the outermost casing protecting USDWs and the well bore is prohibited.

2. Requirements Prior to Receiving Authorization to Inject

Well injection may commence only after all well construction and pre-injection requirements have been met and a written authorization to commence injection has been obtained from the Director.

In order to obtain written authorization to inject, the following must be satisfied:

(a) The Permittee has:

(i). Satisfied the pre-injection requirements contained in APPENDIX A, submitted to the Director a notice of completion of construction and a completed EPA Form 7520-18 with required attachments. If the well construction is different than the approved construction found in APPENDIX A, the Permittee shall also provide a revised well diagram and a description of the modification to the well construction;

(ii). Conducted all applicable logging and testing requirements found in APPENDIX B and submitted required records to the Director. The logging and testing requirements include demonstration of mechanical integrity pursuant to 40 CFR § 146.8, in accordance with the conditions found in Part II, Section C of this permit; and

(iii). Satisfied requirements for corrective action of the Brinkerhoff 3 well contained in APPENDIX F.

(b) The Director has received and reviewed the documentation associated with the requirements in Paragraph 2(a) of this section and finds it is in compliance with the conditions of the Permit.

(c) The Director has inspected the injection well and finds it is in compliance with the conditions of the Permit. If the Permittee has not received notice from the Director of his or her intent to inspect the injection well within 13 days of the date of the notice in Paragraph 2(a)(i) above, then prior inspection is waived.

3. Injection Zone and Fluid Movement

Injection zone means "a geological formation, group of formations, or part of a formation receiving fluids through a well."

Injection and perforations are permitted only within the approved injection zone specified in APPENDIX C. Injected fluids shall remain within the injection zone. If monitoring indicates the movement of fluids from the injection zone, the Permittee shall notify the Director within twenty-four (24) hours and submit a written report that documents circumstances that resulted in movement of fluids beyond the injection zone.

Additional individual injection perforations may be added, provided that they remain within the approved injection zone(s), fracture gradient data submitted is representative of the portion of the injection zone to be perforated, and the Permittee provides notice to the Director in accordance with Part II, Section B.8 for workovers. The Permittee shall also follow the requirements found in Part II Section B.4 *Injection Pressure Limitation* that may result in a change to the permitted MAIP.

4. Injection Pressure Limitation

(a) Injection pressure at the wellhead shall not initiate new fractures or propagate existing fractures in the confining zone. In no case shall injection pressure cause the movement of injectate or formation fluids into a USDW.

(b) Except during stimulation or other well tests approved by EPA, injection pressure shall not exceed the MAIP. The MAIP, as measured at the surface, shall equal the formation fracture pressure (FP) plus friction loss.

MAIP = **FP** + friction loss (if applicable)

The **FP** (measured at the surface) must be calculated using the following equation:

$$\mathbf{FP} = [\mathbf{FG} - (0.433 * (\mathbf{SG} + 0.05))] * \mathbf{D}$$

The values used in the equation are defined as:

"FG" is the fracture gradient of the injection zone in pounds per square inch/feet (psi/ft). The **FG** value for each well shall be determined by conducting a valid step rate test, reviewed and approved by the Director. Alternative methods to the determine a representative **FG** may be used, if approved by the Director.

"SG" is the specific gravity of the injection fluid obtained from a representative fluid sample.

"D" is the true vertical depth in feet. The value for **D** is the depth of the top open perforation.

The current permitted Maximum Allowable Injection Pressure (MAIP) is found in APPENDIX C. This MAIP is calculated using the equation above and data submitted with the permit application.

(c) To determine the MAIP, the Permittee shall submit prior to authorization to inject the following for review: step rate test results to determine the fracture gradient, fluid analysis from a representative sample of the injectate that provides specific gravity, and a revised well diagram (if construction is different than the approved construction found in APPENDIX A, that specifies the depth to top perforation.) The MAIP shall be calculated as described above. The Director will review the information and provide the MAIP in the written authorization to commence injection.

(d) During the life of the Permit, the fracture gradient, top perforation depth, and specific gravity may change. When new perforations are added to the injection zone, the Permittee shall demonstrate that the FG previously submitted is also appropriate for the new interval within the injection zone. It may be necessary to run a new step rate test to gather information from the new interval proposed for injection. Upon submission of monitoring reports, tests, or well workover records that indicate one of these parameters has changed, the MAIP calculation will be evaluated.

When the D or FG value changes, a new MAIP shall be recalculated. When a sample analysis is submitted, the newly submitted SG value will be compared to the SG used to calculate the MAIP. If the absolute difference is greater than 0.05, the MAIP will be recalculated using the newly submitted SG value.

To approve an increase to the MAIP, as a result of changes to the D or FG values, the Director may also require an external (Part II) mechanical integrity demonstration at the increased MAIP.

The Director will notify the Permittee in writing of the revised MAIP. A newly calculated MAIP shall not be implemented until written approval is received from the Director.

(e) Tests to demonstrate external (Part II) Mechanical Integrity (MI) shall be conducted at the most recently approved MAIP. However, if during testing, the Permittee is unable to achieve the MAIP, the MAIP will be readjusted and set to the highest pressure achieved during the successful external Part II Mechanical Integrity Test (MIT). The Permittee will be notified in writing from the Director of the new MAIP, based on the Part II MIT results.

5. Injection Volume Limitation

Injection volume is limited to the total volume specified in APPENDIX C.

6. Injection Fluid Limitation

Injected fluids are limited to and the Permittee may inject those fluids described in APPENDIX C. However, prior to introduction of a new source (e.g., different production formation, well field, fluids that are chemically dissimilar from fluids that are already injecting into the well, etc.) into the well, a fluid analysis shall be required, as listed in APPENDIX D under "PRIOR TO INTRODUCTION OF A NEW SOURCE." The Permittee shall provide a description of the fluid, including the process that generated the fluid, a representative sample of the new fluid source and a notification to the Director, as required in APPENDIX B. Results of the fluid analysis will be used to determine if a new MAIP is required. See Part II, Section B.4 *Injection Pressure Limitation*.

7. Tubing–Casing Annulus

The tubing-casing annulus (TCA) shall be filled with a non-corrosive fluid or other fluid approved by the Director. The TCA valve shall remain closed during normal operations and the TCA pressure shall be maintained between 0 (zero) and the lesser of either 100 psi or ten (10) percent of the tubing pressure.

If TCA pressure cannot be achieved, the Permittee shall report to EPA the actions taken to determine the cause of the excessive pressure and the proposed remedy. If a loss of MI has been determined, the Permittee shall comply with the *Loss of Mechanical Integrity* requirements found in Part II, Section C.5.

8. Alteration, Workover, and Well Stimulation

Alterations, workovers, and well stimulations shall meet all conditions of the Permit. Alteration, workover, and well stimulation include any activity that physically changes the well construction (casing, tubing, packer) or injection formation.

Prior to beginning any addition or physical alteration to an injection well's construction or injection formation, the Permittee shall give advance notice to the Director. Additionally, the Director's written approval must be obtained if the addition or physical alteration to the injection well modifies the approved well construction. Substantial alterations or additions may be cause for modification to the permit and may include additional testing or monitoring requirements.

The Permittee shall record all alterations, workovers, and well stimulations on a Well Rework Record (EPA Form 7520-19) and submit a revised well construction diagram, when the well construction has been modified. The Permittee shall provide this and any other record of well workover, logging, or test data to EPA within thirty (30) days of completion of the activity.

The Permittee shall complete any activity which affects the tubing, packer, or casing and provide demonstration of internal (Part I) MI within ninety (90) days of beginning the activity. If the Permittee is unable to complete work within the specified time period, the Permittee shall propose an alternative schedule and obtain Director's written approval. Injection operations shall not resume until the well has successfully demonstrated mechanical integrity. If the well lost mechanical integrity, the Permittee must receive written approval from the Director to recommence injection.

9. Well Logging and Testing

Well logging and testing requirements are found in APPENDIX B. The Permittee shall ensure the log and test requirements are performed within the time frames specified in APPENDIX B. Well logs and tests shall be performed according to current EPA-approved procedures. The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

Section C. MECHANICAL INTEGRITY

1. Requirement to Maintain Mechanical Integrity

The Permittee is required to ensure the injection well maintains MI at all times. Injecting into a well that lacks MI is prohibited.

An injection well has MI if:

(a) there is no significant leak in the casing, tubing, or packer (internal Part I); and

(b) there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (external Part II).

2. Demonstration of Mechanical Integrity

The conditions under which the Permittee shall conduct the MI testing are as follows and detailed in APPENDIX B:

(a) Prior to receiving authorization to inject and periodically thereafter as specified in APPENDIX B, the Permittee shall demonstrate both internal Part I and external Part II MI. Well-specific conditions dictate the methods and the frequency for demonstrating MI and are specified in APPENDIX B.

(b) After any rework that compromises the MI of the well and after a loss of MI.

Other than during periods of well workover (maintenance) in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the Permittee shall monitor injection tubing pressure, rate, and volume, pressure on the annulus between tubing and casing, and bradenhead pressure, as specified in APPENDIX D.

The Director may require additional or alternative tests if the results presented by the operator are not satisfactory to the Director to demonstrate there is no movement of fluid into or between USDWs resulting from the injection activity.

Results of any MIT results required by this Permit shall be submitted to the Director as soon as possible but no later than thirty (30) calendar days after the test is complete.

3. Mechanical Integrity Test Methods and Criteria

EPA-approved methods shall be used to demonstrate MI. These methods may be found in documents available from EPA at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance:

- *"Ground Water Section Guidance No. 34: Cement Bond Logging Techniques and Interpretation"*
- *"Ground Water Section Guidance No. 39: Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity"*
- *"Radioactive Tracer Surveys for Evaluating Fluid Channeling Behind Casing near Injection Perforations"*
- *"Temperature Logging for Mechanical Integrity"*

Current versions of these documents will also be available from EPA upon request. The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

4. Notification Prior to Testing

The Permittee shall notify the Director at least thirty (30) calendar days prior to any MIT. The Director may allow a shorter notification period if it would be sufficient to enable EPA to witness the MIT or EPA declines to witness the test. Notification may be in the form of a yearly or quarterly schedule of planned MITs, or it may be on an individual basis.

5. Loss of Mechanical Integrity

If the well fails to demonstrate MI during a test or a loss of MI becomes evident during operation (such as presence of pressure in the tubing-casing annulus, water flowing at the surface, etc.), the Permittee shall notify the Director within twenty-four (24) hours (see Part III, Section D.11(e) of this Permit), cease injection and shut-in the well within forty-eight (48) hours unless the Director requires immediate shut-in.

Within five (5) calendar days, the Permittee shall submit a follow-up written report that documents circumstances that resulted in the MI loss and how it was addressed. If the MI loss has not been resolved, the Permittee shall provide a report with the proposed plan and schedule to reestablish MI. A demonstration of MI shall be reestablished within ninety (90) calendar days of any loss of MI unless written approval of an alternate time period has been given by the Director.

Injection operations shall not resume until after the MI loss has been resolved, the well has demonstrated MI pursuant to 40 CFR § 146.8, and the Director has provided written approval to resume injection.

Section D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Monitoring Parameters and Frequency

Monitoring parameters are specified in APPENDIX D. The listed parameters are to be monitored, recorded and reported at the frequency indicated in APPENDIX D, even when the well is not operating. In the event the well has not injected or is no longer injecting, the monitoring report will reflect its status. Sampling data shall be submitted if the well has injected any time during the reporting period.

Records of monitoring information shall include:

(a) the date, exact place, and time of the observation, sampling, or measurements;

(b) the individual(s) who performed the observation, sampling, or measurements;

(c) the date(s) of analyses and individuals who performed the analyses;

(d) the analytical technique or method used; and

(e) the results of such analyses.

2. Monitoring Methods

Observations, measurements, and samples taken for the purpose of monitoring shall be representative of the monitored activity and include:

(a) Methods used to monitor the nature of the injected fluids must comply with analytical methods cited and described in 40 CFR § 136.3 or by other methods that have been approved in writing by the Director.

(b) Injection tubing, TCA annulus, and bradenhead pressures, injection rate, injected volume, and cumulative injected volume shall be observed and recorded at the wellhead. All parameters shall be observed simultaneously to provide a clear depiction of well operation. Annulus pressure applied during standard annulus pressure tests performed during mechanical integrity tests should not be included in the annual monitoring report.

(c) Pressures are to be measured in pounds per square inch (psi).

(d) Fluid volumes are to be measured in standard oil field barrels (bbl) or thousands of cubic feet (MCF).

(e) Injection rates are to be measured in barrels per day (bbl/day) or thousands of cubic feet per day (MCF/day).

3. Records Retention

The Permittee shall retain records of all monitoring information, including the following:

(a) Calibration and maintenance records and all original recordings for continuous monitoring instrumentation, copies of all reports required by this Permit, for a period of at least (3) years from the date of the sample, measurement, or report. This period may be extended any time prior to its expiration by request of the Director.

(b) Nature and composition of all injected fluids until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under 40 CFR § 144.52(a)(6). The Permittee shall continue to retain the records after the three-year (3) retention period unless the Permittee delivers the records to the Regional Administrator, or his/her authorized representative, or obtains written approval from the Regional Administrator, or his/her authorized representative, to discard the records.

4. Annual Reports

Regardless of whether or not the well is operating, the Permittee shall submit an Annual Report to the Director that:

(a) summarizes the results of the monitoring required in Part II, Section D and APPENDIX D;

(b) includes a summary of any major changes in characteristics or sources of injected fluid. The report of fluids injected during the year must identify each new fluid source by well name and location, and the field name or facility name; and

(c) includes any additional wells within the area of review that have not previously been submitted. For those wells that penetrate the injection zone, a well construction diagram, cement records and cement bond log are also required.

The first Annual Report shall cover the period from the effective date of the Permit through December 31 of that year. Subsequent Annual Reports shall cover the period from January 1 through December 31 of the reporting year. Annual Reports shall be submitted by February 15 of the year following data collection. EPA Form 7520-8 or 7520-11 may be used or adapted to submit the Annual Report, however, the monitoring requirements specified in this Permit are mandatory even if the EPA form indicates otherwise. An electronic form may also be obtained from EPA to satisfy reporting requirements.

Section E. PLUGGING AND ABANDONMENT

1. Notification of Well Abandonment

The Permittee shall notify the Director in writing at least thirty (30) days prior to plugging and abandoning an injection well. The notification shall include any anticipated changes to the plugging and abandonment plan (P&A Plan), which will be incorporated into the Permit as a modification.

2. Well Plugging Requirements

Prior to abandonment, the injection well shall be plugged with cement in a manner which isolates the injection zone and will not allow the movement of fluids into or between USDWs, in accordance with 40 CFR § 146.10. Additional federal, state or local laws or regulations may also apply.

3. Approved Plugging and Abandonment Plan

The approved P&A Plan and required tests are incorporated into this Permit as APPENDIX E. Changes to the approved P&A Plan will be incorporated into the Permit as a modification prior to beginning plugging operations and shall be submitted using EPA Form 7520-19. The Director also may require revision of the approved P&A Plan at any time prior to plugging the well.

4. Plugging and Abandonment Report

Within sixty (60) days after plugging a well, the Permittee shall submit a report (EPA Form 7520-19) to the

Regional Administrator or his/her authorized representative. The plugging report shall be certified as accurate by the person who performed the plugging operation. Such report shall consist of either:

(a) a statement that the well was plugged in accordance with the approved P&A Plan; or

(b) where actual plugging differed from the approved P&A Plan found in APPENDIX E, an updated version of the plan, specifying the differences.

5. *Wells Not Actively Injecting*

After any period of two (2) years during which there is no injection, or two (2) years from the spud date of a newly drilled well or the permit effective date of a well to be converted to an injector, the Permittee shall plug and abandon the well in accordance with Part II, Section E.2 and APPENDIX E of this Permit unless the Permittee:

(a) provides written notice to the Regional Administrator or his/her authorized representative, prior to the two-year (2) period;

(b) describes actions or procedures, satisfactory to the Regional Administrator or his/her authorized representative, that the Permittee will take to ensure that the well will not endanger USDWs during the period of temporary abandonment. These actions and procedures shall include compliance with the technical requirements applicable to active injection wells, unless waived by the Regional Administrator or his/her authorized representative; and

(c) receives written notice by the Regional Administrator or his/her authorized representative to temporarily waive plugging and abandonment requirements.

The Permittee of a well that has been temporarily abandoned shall notify the Director prior to resuming operation of the well.

PART III. CONDITIONS APPLICABLE TO ALL PERMITS

Section A. CHANGES TO PERMIT CONDITIONS

1. Modification, Revocation and Reissuance, or Termination

The Director may, for cause, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR §§ 124.5, 144.12, 144.39, 144.40, and 144.41. The filing of a request for modification, revocation and reissuance, termination, or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any condition of this Permit.

2. Conversion to Non-UIC Well

The Director may allow conversion of the well to a non-UIC well. Conversion may not proceed until the Permittee receives written approval from the Director, at which time this permit will expire due to the end of operating life of the facility. Once expired under this part, the Permittee will need to reapply for a UIC permit and restart the complete permit process, including opportunity for public comment, before injection can occur.

Conditions of such conversion shall include approval of the proposed well rework, demonstration of mechanical integrity, and documentation that the well is authorized by another regulatory agency.

3. Transfer of Permit

Under 40 CFR § 144.38, this Permit may be transferred by the Permittee to a new owner or operator only if:

(a) the Permit has been modified or revoked and reissued (under 40 CFR § 144.39(b)(2)), or a minor modification made (under 40 CFR § 144.41(d)), to identify the new permittee and incorporate such other requirements as may be necessary under the SDWA, or

(b) the Permittee provides written notification (EPA Form 7520-7) to the Director at least thirty (30) days in advance of the proposed transfer date and submits a written agreement between the existing and proposed new permittees containing a specific date for transfer or permit responsibility, coverage, and liability between them, and demonstrates that the financial responsibility requirements of 40 CFR § 144.52(a)(7) have been met by the proposed new permittee. If the Director does not notify the Permittee and the proposed new permittee of his or her intent to modify or revoke and reissue, or modify, the transfer is effective on the date specified in the written agreement. A modification under this paragraph may also be a minor modification under 40 CFR § 144.41.

4. Permittee Change of Address

Upon the Permittee's change of address, or whenever the operator changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within thirty (30) days.

Section B. SEVERABILITY

The provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance is held invalid, the application of such provision to other circumstances, and the remainder of this Permit shall not be affected thereby. Additionally, in a permit modification, only those conditions to be modified shall be reopened. All other aspects of the existing permit shall remain in effect for the duration of the permit.

Section C. CONFIDENTIALITY

In accordance with 40 CFR part 2 and 40 CFR § 144.5, information submitted to EPA pursuant to these regulations may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the information will be treated in accordance with the procedures in 40 CFR part 2 (Public Information). Claims of confidentiality for the following information will be denied:

- the name and address of the Permittee; and
- information which deals with the existence, absence or level of contaminants in drinking water.

Section D. ADDITIONAL PERMIT REQUIREMENTS

1. *Prohibition on Movement of Fluid Into a USDW*

The Permittee shall not construct, operate, maintain, convert, plug, abandon or conduct any other injection activity in a manner that allows the movement of a fluid containing any contaminant into USDWs, except as authorized by 40 CFR part 146.

2. *Duty to Comply*

The Permittee must comply with all conditions of this Permit. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application; except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration as such noncompliance is authorized in an emergency permit under 40 CFR § 144.34. All violations of the SDWA may subject the Permittee to penalties and/or criminal prosecution as specified in Section 1423 of the SDWA.

3. *Need to Halt or Reduce Activity Not a Defense*

The Permittee shall not use as a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

4. *Duty to Mitigate*

The Permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

5. *Proper Operation and Maintenance*

The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances), which are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

6. *Permit Actions*

This Permit may be modified, revoked and reissued or terminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. *Property and Private Rights; Other Laws*

This Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of any other federal, state or local law or regulations.

8. *Duty to Provide Information*

The Permittee shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to the Director, upon request, copies of records required to be kept by this Permit.

9. *Inspection and Entry*

The Permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

(a) enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this Permit;

(b) have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;

(c) inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and

(d) sample or monitor at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

10. Signatory Requirements

All applications, reports or other information submitted to the Regional Administrator or his/her authorized representative shall be signed and certified according to 40 CFR § 144.32. This section explains the requirements for persons duly authorized to sign documents and provides wording for required certification.

11. Reporting Requirements

Copies of all reports and notifications required by this Permit shall be signed and certified in accordance with the requirements under Part III, D.10 of this Permit and shall be submitted to EPA:

UIC Enforcement, Mail Code: 8ENF-W-SD
U.S. Environmental Protection Agency
1595 Wynkoop Street
Denver, Colorado 80202-1129

All correspondence should reference the well name and location and include the EPA Permit number.

(a) Monitoring Reports. Monitoring results shall be reported at the intervals specified elsewhere in this Permit.

(b) Planned changes. The Permittee shall give notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted well, and prior to commencing such changes.

(c) Anticipated noncompliance. The Permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with Permit requirements.

(d) Compliance schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted no later than thirty (30) calendar days following each schedule date.

(e) Twenty-four hour reporting. The Permittee shall report to the Director any noncompliance which may endanger human health or the environment, including:

(i) any monitoring or other information, which indicates that any contaminant may cause an endangerment to a USDW; or

(ii) any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

Information shall be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the Permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting EPA Region 8 UIC Program SDWA Enforcement Supervisor, or by contacting EPA Region 8 Emergency Operations Center at (303) 293-1788.

In addition, a follow up written report shall be provided to the Director within five (5) calendar days of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance including exact dates and times, and if the noncompliance has not been corrected the anticipated time it is expected to continue;

and the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(f) Other Noncompliance. The Permittee shall report all instances of noncompliance not reported under Paragraphs 11(a), 11(b), 11(d), or 11(e) of this Section at the time the monitoring reports are submitted. The reports shall contain the information listed in Paragraph 11(e) of this Section.

(g) Other information. Where the Permittee becomes aware that it failed to submit any relevant facts in a permit application or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall submit such facts or information to the Director within thirty (30) days of discovery of failure.

(h) Oil Spill and Chemical Release Reporting. The Permittee shall comply with all reporting requirements related to the occurrence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802 or NRC@uscg.mil.

Section E. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility

The Permittee, including the transferor of a permit, is required to demonstrate and maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director until:

- The well has been plugged and abandoned in accordance with an approved plugging and abandonment plan pursuant to 40 CFR §§144.51(o) and 146.10, and the Permittee has submitted a plugging and abandonment report pursuant to 40 CFR §144.51(p); or
- The well has been converted in compliance with the requirements of 40 CFR §144.51(n); or
- The transferor of a permit has received notice from the Director that the owner or operator receiving transfer of the permit, the new Permittee, has demonstrated financial responsibility for the well.

No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

2. Types of Adequate Financial Responsibility.

Adequate financial responsibility to properly plug and abandon injection wells under the Federal UIC requirements must include completed original versions of one of the following:

(a) a surety bond with a standby trust agreement,

(b) a letter of credit with a standby trust agreement,

(c) a fully funded trust agreement, or

(d) a financial test and corporate guarantee.

A standby trust agreement acceptable to the Director shall contain wording identical to model language provided to the Permittee by EPA and must accompany any surety bond or letter of credit. Annual reports from the financial institution managing the standby trust account shall be submitted to the Director showing the available account balance.

A surety bond acceptable to the Director shall contain wording identical to model language provided to the Permittee by EPA and shall be issued by a surety bonding company found to be acceptable to the U.S. Department of Treasury, which can be determined by review of that Department's Circular #570, currently available on the internet at https://fiscal.treasury.gov/surety-bonds/circular-570.html.

A letter of credit acceptable to the Director shall contain wording identical to model language provided to the Permittee by EPA and be issued by a bank or other institution whose operations are regulated and examined by a state or federal agency.

A fully funded trust agreement acceptable to the Director shall contain wording identical to model language provided to the Permittee by EPA. Annual reports from the financial institution managing the trust account shall be submitted to the Director showing the available account balance.

An independently audited financial test with a corporate guarantee acceptable to the Director shall contain wording identical to model language provided to the Permittee by EPA and shall demonstrate that the Permittee meets or exceeds certain financial ratios. The Permittee must meet EPA's requirements including, but not limited to, total net worth to be able to use this method. If this financial instrument is used, it must be resubmitted annually, within ninety (90) calendar days after the close of the Permittee's fiscal year, using the financial data available from the most recent fiscal year. If at any time the Permittee does not meet the financial ratios, notice to EPA must be provided within 90 days and a new demonstration of financial responsibility must be submitted within 120 days.

The Permittee shall submit a completed, originally-signed financial responsibility demonstration to:

UIC Financial Responsibility Coordinator
Mail Code: 8ENF-W-SD
U.S. Environmental Protection Agency
1595 Wynkoop Street
Denver, Colorado 80202-1129

3. Determining How Much Coverage is Needed

The Permittee, when periodically requested to revise the plugging and abandonment cost estimate discussed above, may be required to adjust the given cost for inflation or pursue a new cost estimate as prescribed by the Director.

4. Insolvency

In the event of:

(a) the bankruptcy of the trustee or issuing institution of the financial mechanism;

(b) suspension or revocation of the authority of the trustee institution to act as trustee; or

(c) the institution issuing the financial mechanism losing its authority to issue such an instrument,

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) calendar days after any event specified in (a), (b), or (c) above.

The Permittee must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or operator as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, must make such a notification as required under the terms of the guarantee.

APPENDIX A

WELL CONSTRUCTION REQUIREMENTS

The well shall be constructed in a manner to prevent the movement of fluids into or between USDWs, and in accordance with 40 CFR § 146.22 and other applicable federal, state or local laws and regulations. General requirements include:

- The well shall be completed with at least two cemented casing strings set within a drilled hole.
- The casing and cement used in the construction of the well shall be designed for the life expectancy of the well, including the natural and applied pressures expected during the life of the well.
- The well shall be completed with injection tubing set on at least one packer.
- The uppermost packer must be set within 100 feet of the uppermost open perforation.

WELL CONSTRUCTION AND REQUIRED MODIFICATIONS:

- 8-5/8" J-55, #24 surface casing set in a 13-3/4" hole to an estimated depth of 509 feet-Kelly Bushing (ft-KB) and cemented to surface with 500 sacks regular cement.

- 5-1/2" J-55, #17 production casing set in an 7-7/8" hole to a depth of 6,939 ft-KB and cemented with 450 sacks of 50% POSMIX and 2% Gel. Top of cement reported at 5,514 ft-KB

- 2-7/8" tubing shall be installed with a packer set at the depth of about 5,707 ft-KB and no more than 100 feet above the top perforation.

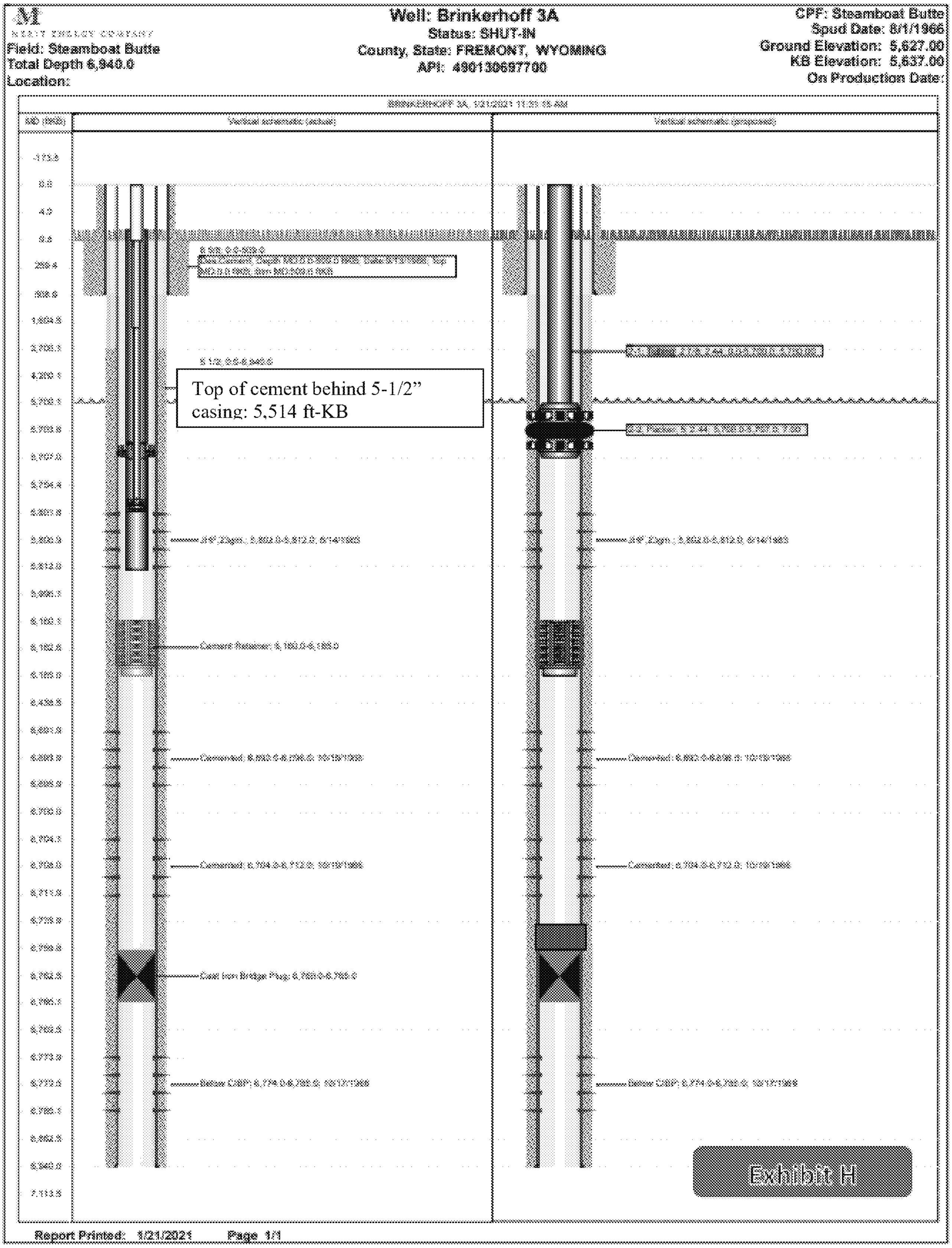
- Prior to receiving authorization to inject, the permittee shall place a minimum 20-foot cement plug, depicted in purple in Exhibit H below, on top of the cast iron bridge plug set at 6,760 ft-KB.

- Prior to receiving authorization to inject, the permittee shall submit for EPA review, comment and approval and subsequently implement a plan to squeeze a sufficient volume of cement behind the 5-1/2" production casing to isolate the Nugget Sandstone and Sundance Formation from overlying USDWs. A cement bond log (CBL) showing a minimum continuous interval of 18 feet with greater than an 80% cement bond index must be run following the cement squeeze to demonstrate isolation behind the 5-1/2" production casing.

  Alternatively, a stationary, non-injecting noise log (e.g., Spectral Noise Log) may be recorded at pre-determined and approved depths/durations across and above the top of the Nugget Sandstone, Sundance Formation, Lakota Sandstone, Dakota Sandstone, Muddy Sandstone and Frontier Formation. Additional depth stations may be added as necessary to delineate any fluid entry or movement identified during logging. The log must be run in the open 5-1/2" production casing prior to placement of tubing and packer. This log will be run to assess for fluid movement occuring behind the 5-1/2" production casing into or between USDWs identified in the Statement of Basis. A plan detailing the proposed logging tool and procedure shall be submitted for EPA review, comment and approval prior to logging the well and should following guidance available in the July 1994, EPA/600/R-94-124 publications titled "Temperature, Radioactive Tracer, and Noise Logging for Injection Well Integrity". For this alternative to be an acceptable substitute, the results and analysis of the noise log must be submitted for EPA review, comment and approval and demonstrate that fluid movement is not occuring into or between USDWs behind the 5-1/2" production casing. If the Director determines that the results and analysis of the noise log are inconclusive or show evidence of fluid movement into or between USDWs behind the 5-1/2" production casing, the permittee shall submit for EPA review, comment and approval and subsequently implement a plan to cement the 5-1/2" production casing to prevent fluid movement into or between USDWs.

No well stimulation program is proposed during well completion. In the event the Permittee wishes to conduct well stimulation, the Permittee shall follow the requirements in Part II, Section B.8. *Alteration, Workover, and Well Stimulation.*

INJECTION WELL CONSTRUCTION DIAGRAM



APPENDIX B

LOGGING AND TESTING REQUIREMENTS

Well logging and tests shall be performed according to EPA approved procedures. It is the responsibility of the Permittee to obtain and use these procedures prior to conducting any well logging or test required as a condition of this Permit. These procedures can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

Well logs and test results shall be submitted to the Director within sixty (60) calendar days of completion of the logging or testing activity and shall include a report describing the methods used during logging or testing and an interpretation of the log or test results. When applicable, the report shall include a descriptive report prepared by a knowledgeable log analyst, interpreting the results of that portion of those logs and tests which specifically relate to: (1) a USDW and the confining zone adjacent to it, and (2) the injection zone and adjacent formations.

LOGS AND TESTS

TYPE OF LOG OR TEST	DATE DUE
Well logs and test results shall be submitted to the Director within sixty (60) calendar days of completion of the logging or testing activity.	
Injectate Water Analysis A representative water sample of the injectate shall be analyzed for the constituents found in APPENDIX D.	1. Annually 2. Prior to the introduction of a new source.
Injection Zone Water Sample A representative water sample from each discrete injection zone shall be analyzed for the constituents found in APPENDIX D. After purging a minimum of three successive wellbore volumes, a representative sample shall be determined by stabilized specific conductivity. A log recording data (e.g., initial fluid level, volume purged with each swab run, fluid level in between swab runs, specific conductivity after each swab run, etc.) gathered throughout well purging activities shall be recorded and reported with the water sample results. The sampling procedure should follow immediately after perforating an interval in order to prevent wellbore fluids from contaminating the naturally occurring injection formation water. If the Total Dissolved Solids (TDS) concentration of the Crow Mountain Sandstone is less than 10,000 mg/L, an aquifer exemption must be approved by the Director prior to receiving authorization to inject.	Prior to receiving Authorization to Inject.
Injection Formation Fluid Pressure	Prior to receiving Authorization to Inject.
Step Rate Test (SRT) The SRT shall be performed following current EPA guidance. The SRT shall be conducted with both surface and bottom-hole pressure gauges. This	Prior to receiving Authorization to Inject.

requirement may be waived with a written approval from the Director.	
Standard Annulus Pressure (internal Part I MI) If the well has not received authorization to inject and does not have tubing installed, in lieu of the Standard Annulus Pressure test, a Casing Pressure Test can be performed.	1. Prior to receiving Authorization to Inject or within two (2) years of the permit effective date. 2. Prior to recommencing injection after any well rework that compromises the internal mechanical integrity of the well or a loss of MI. 3. At least once every five (5) years after the last successful demonstration of internal (Part I) Mechanical Integrity.
Radioactive Tracer Survey (RTS) The radioactive tracer survey will include an injectivity profile and channel check(s) to show which perforations in the injection zone(s) are taking the injected fluid and to demonstrate that no fluid is channeling in cement behind the production casing above or below the approved injection zone described in APPENDIX C.	1. Prior to receiving Authorization to Inject.
Temperature Survey (external Part II MI) The temperature survey shall be logged from ground level to the total depth (or plug-back total depth) of the well unless an alternative logging interval has been approved by the Director. As required in Part II, Section C.3, the temperature survey must be run in accordance with EPA Region 8 Guidance titled "Temperature Logging for Mechanical Integrity".	1. Prior to receiving Authorization to Inject. A baseline temperature log must be run prior to any test related injection activities, and a shut-in temperature survey must be completed concurrently with the end of the step rate test. 2. Conducted within one (1) year after any approved increase of the MAIP pursuant to Part II, Section B.4(e).

APPENDIX C

OPERATING REQUIREMENTS

FLUID LIMITATION:
Injected fluids are limited to those used for enhanced recovery of oil or natural gas, as defined in 40 CFR § 144.6(b)(2).

This Permit does not allow for the injection of any hazardous waste as defined in 40 CFR § 261.3. Injection of any substance defined as a hazardous waste, whether hazardous by listing or characteristic, is a violation of this permit and requires notification under Part III, Section D.11. This well is not approved for commercial brine injection or injection of fluids defined in 40 CFR § 144.6(b)(1) for the purpose of fluid disposal.

INJECTION ZONE:
Injection is permitted only within the approved injection zone listed below.

APPROVED INJECTION ZONE (GL, ft.)

FORMATION NAME or STRATIGRAPHIC UNIT	TOP (ft-KB) *	BOTTOM (ft-KB) *
Crow Mountain Sandstone Member of the Chugwater Formation[1]	5,702	5,813

*estimated top and bottom depths of formations relative to a KB of 10 ft.

MAXIMUM ALLOWABLE INJECTION PRESSURE:

The parameters below are the values used to calculate the initial authorized MAIP issued with this Permit. These parameters may be updated throughout the life of well, pursuant to the conditions and formula at Part II.B.4 of this Permit. Documentation to support a change shall be provided and approved by the Director prior to recalculation of the MAIP.

MAIP Parameters

fracture gradient	specific gravity*	depth (ft-KB)	friction loss (PSI)	Calculated MAIP (PSI)	**Temporary MAIP (PSI)**
0.564[1]	1.057	5,802	N/A	620	620

**From the MAIP equation in Part II, Section B.4(b), SG+0.05 or 1.057.*

[1] Frac gradient proposed by applicant based on an Instantaneous Shut-in Pressure (ISIP) recorded following a fracture stimulation of the Crow Mountain Sandstone at the Brinkerhoff 4 well with a factor of safety applied.

MAXIMUM INJECTION VOLUME:

There is no limitation on the fluid volume permitted to be injected into this well. In no case shall injection pressure exceed the MAIP.

If an aquifer exemption is required and approved for this Permit, then a volume limit will be set based on the conditions of the aquifer exemption, through the modification process.

APPENDIX D

MONITORING AND REPORTING PARAMETERS

This is a listing of the parameters required to be observed, recorded, and reported. Refer to the Part II, Section D of the Permit, for detailed requirements for observing, recording, and reporting of these parameters.

EPA Form 7520-8 or 7520-11 may be used or adapted to submit the Annual Report. An electronic form may also be obtained from EPA to satisfy reporting requirements.

OBSERVE WEEKLY AND RECORD MONTHLY	
OBSERVE AND RECORD	Injection Tubing Pressure (psi)
	Bradenhead Pressure (psi)
	Annulus Pressure (psi)
	Injection Rate (bbl/day)
	Injected Volume (bbl)
	Cumulative Fluid Volume Injected (since injection began) (bbls)

WITH THE FIRST ANNUAL REPORT AFTER RECEIVING AUTHORIZATION TO INJECT AND PRIOR TO INTRODUCTION OF A NEW SOURCE Analytical methods used must comply with the methods cited in Table 1 of 40 CFR § 136.3, Appendix II of 40 CFR § 261, or those methods listed below	
ANALYZE	Analyze a sample of injection fluids for the following constituents: • Total Dissolved Solids (mg/L) via Method 2540 C-97 • pH via Method 4500-H+ B-00 • Specific gravity via Method SM 2710 F • Conductivity/Specific Conductance (S/m) via Method 2510 B-97 • Cations: B, Ba, Ca, Fe, K, Li, Mn, Mg, Na, and Sr via EPA Method 200.7, 200.8 • Anions: Br, I, Cl and SO_4 via Method D6508, Rev. 2 HCO_3 via Method SM 2320 B CO_3 via Method 310.1 • Ammonia as N via Method 350.1, 350.2 or 350.3 • Uranium and Radium via Method 7500 Alternative analysis methods may be used, if pre-approved.

ANNUALLY (if injection occurred during reporting period) Analytical methods used must comply with the methods cited in Table 1 of 40 CFR § 136.3, Appendix II of 40 CFR § 261, or those methods listed below

ANALYZE	Analyze a sample of injection fluids for the following constituents: • Total Dissolved Solids (mg/L) via Method 2540 C-97 • pH via Method 4500-H+ B-00 • Specific gravity via Method SM 2710 F • Conductivity/Specific Conductance (S/m) via Method 2510 B-97 Alternative analysis methods may be used, if pre-approved.

ANNUALLY	
REPORT	Each month's maximum and average injection tubing pressures (psi)
	Each month's maximum and minimum annulus pressures (psi)
	Each month's maximum and minimum bradenhead pressures (psi)
	Each month's maximum and average injection rate (bbl/day)
	Each month's injected volume (bbl)
	Fluid volume injected since the well began injecting (bbl)
	Written results of annual injected fluid analysis
	Sources of all fluids injected during the year, including any wellfield and formation, noting any major changes in characteristics of injected fluid.

In addition to these items, additional logging and testing results may be required periodically. For a list of those items and their due dates, please refer to APPENDIX B – LOGGING AND TESTING REQUIREMENTS.

APPENDIX E

PLUGGING AND ABANDONMENT (P&A) REQUIREMENTS

All wells shall be plugged with cement in a manner which isolates the injection zone and will not allow the movement of fluids either into or between USDWs in accordance with 40 CFR § 146.10. Additional federal, state or local law or regulations may also apply. General requirements applicable to all wells include:

- Prior to plugging a well, mechanical integrity must be established unless the P&A plan will address the mechanical integrity issue. Injection tubing shall be pulled.
- Cement plugs shall have sufficient compressive strength to maintain adequate plugging effectiveness.
- Each plug placement, unless above a retainer or bridge plug, must be verified by tagging the top of the plug after the cement has had adequate time to set.
- If there is more than 2,000 mg/L difference of TDS between individual exposed USDWs, they must be isolated from each other.
- Water-based muds, or brines containing a plugging gel, with a density of at least 9.2 pounds per gallon should be used during plugging operations and should remain between plugs in the well after cement plug placement.

At a minimum, the following plugs are required:

1. **Isolate the Injection Zone**: Remove down hole apparatus from the well and perform necessary clean out; displace well fluid with plugging gel.
   PLUG 1: Squeeze injection zone perforations. Set a cast iron bridge plug (CIBP) within the innermost casing string between ~50 to 100 feet above the top perforations with a minimum 25-sack cement plug on the top of the CIBP.

2. **Isolate the Sundance Formation and Nugget Sandstone from overlying USDWs**:
   PLUG 2: Perforate production casing at or near 4,967 feet, which corresponds to the base of the Morrison Formation, and attempt to circulate behind the production casing annulus. Set a cast iron cement retainer (CICR) at or near 4,967 feet and pump a sufficient volume of cement through the CICR to isolate the Sundance Formation and Nugget Sandstone from overlying USDWs behind the 5-1/2" production casing. Place 25 sacks of cement on top of the CICR. For conformance with 40 CFR § 146.10(a), this plug is in addition to those proposed in the P&A plan included in the permit application and is depicted in purple in the diagram below.

3. **Isolate the Frontier Formation from sandstones of the Cody Shale:**
   PLUG 3: Perforate production casing at or near 3,000 feet and attempt to circulate behind the production casing annulus. Set a CICR at 2,975 feet and pump a 100-sack plug through the CICR. Place 25 sacks of cement on top of the CICR.

4. **Isolate Quaternary deposits from sandstones of the Cody Shale:**
   PLUG 4: Perforate production casing at or near 509 feet and attempt to circulate up through the surface casing-production casing annulus. Set a cast CICR at or near 509 feet and pump a sufficient volume of cement to cover at least 50 above the base of the surface casing shoe. Place 25 sacks of cement on top of the CICR. For conformance with 40 CFR § 146.10(a), this plug is in addition to those proposed in the P&A plan included in the permit application and is depicted in purple in the diagram below.

5. **Isolate Surface Fluid Migration Paths**:
   PLUG 5: Pull out to 200 feet below surface. Perforate squeeze hole. Pump 50 sacks of cement until cement returns to surface. Wait on cement and top off inside 5-1/2" production casing if level falls during curing. Cut casing 4 below grade, weld on dry hole plate with legal ID. Remove Rig anchors. The cement plug set inside and outside of the 5-1/2" production casing string must extend from 200 feet to the surface.

INJECTION WELL P&A DIAGRAM

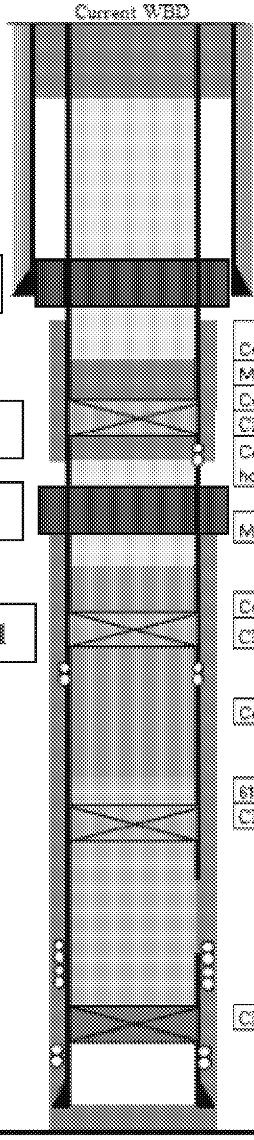
MERIT ENERGY COMPANY

LEASE & WELL NO.	Brinkerhoff 3A	WBD	Proposal for P&A WBD
FIELD NAME	Steamboat Butte	COUNTY, ST	Fremont, Wyoming
LOCATION	330' FSL & 330' FEL of NW/4 Sect. 9 T5N R1W	API NO.	4901306977
DATE	6/18/2021	PREPARED BY	N. Lahutsky

Note this is not an actual WBD, but the proposal for the plugging procedure

K.B. ELEV.	5637'
D.F. ELEV.	10'
GR.LEVEL	5,627

Current WBD



PLUG #5

PLUG #4

PLUG #3

PLUG #2

PLUG #1

SURFACE CASING

SIZE 8 5/8" WEIGHT 24 #
GRADE H40 SX. CMT. 500 sx
DEPTH 509' TOC @ surface

PRODUCTION CASING

SIZE 5 1/2" WEIGHT 15.5#
GRADE K55 SX. CMT. 450 sx
DEPTH 6939' TOC @ 5514'

WELL HISTORY

8/1/1968	Well drilled down through Phosphoria, cement casing and perforated the Phosphoria replace the failed Brinkerhoff 3. IP 205 BOPD and 379 BWPD from Phosphoria
6/2/1983	Plug back Phosphoria. Recomplete to Curtis and Frac. Frac screened out immediately and was unsuccessful.
6/1/1990	Well status changed to D... been done to this well si...
5/1/2021	Application for conversi... submitted to EPA. This P&A procedure WBD is a part of that application.

Cement Plug - 50 sx through squeeze hole at 200'. Surface -

Mud plug

Cement Plug - 25 sx on top of CICR at 2975'. 2785'-2975'

CICR 2975'

Cement Plug - 100 sx through CICR at 2975' and squeeze holes 3000'.

Mud plug

Cement Plug - 25 sx on top of CICR at 5750'. 5540'-5750'

CICR 5750'

Curtis Perfs
5802'-5812'

Cement Plug - 50 sx through CICR at 5750'. 6172' - 5750'

6172'-6180'Cement on top of CICR

CICR 6180'-6185'.

Phos Perfs (Plugged)
6692'-6696'
6704'-6712'

CIBP 6760' - 6765'

Phos Perfs (Plugged)
6774'-6785'

PBTD @ PA'd
TD @ 6940'

Formation Tops	Depth (MD)
Frontier	3,005
U. Muddy	4,249
L. Muddy	4,272
Dakota	4,466
Lakota	4,751
Sundance	4,967
Nugget	5,421
Chugwater	5,539
Dinwoody	6,650
Phosphoria	6,756
Tensleep	N/a

APPENDIX F

CORRECTIVE ACTION PLAN

A review of well completion and P&A records submitted for wells located within the AOR identified one (1) well requiring corrective action as a condition for receiving authorization to inject under this Permit. Corrective action is necessary to ensure that injected fluids remain in the authorized injection zone as required in Part II, Section B.3 of this permit and to prevent movement of fluid into an Underground Source of Drinking Water, as defined in 40 CFR § 144.3. The well is listed in the table below.

Well Name	Location	API #
Brinkerhoff 3	Sec 9, T3N-R1W	49-013-06367

Corrective Actions:
The following corrective actions must be completed prior to receiving authorization to inject:

1. The Permittee must submit and subsequently implement a plan to isolate the upper confining zone at the Brinkerhoff 3 well following EPA review, comment and approval. This plan shall include, but not be limited to:

    a. A plan to locate and re-enter the wellbore;

    b. A plan to drill out existing cement plugs to the base of the upper confining zone above the Crow Mountain Sandstone, or as near as practicable based on wellbore conditions;

    c. A plan to run a CBL to identify the top of cement behind the 7" production casing and delineate uncemented or compromised intervals across the upper confining zone and in between the Crow Mountain Sandstone and the Lakota Sandstone.

    d. A plan to perforate the 7" production casing and squeeze cement at, or as near as practicable based on wellbore conditions, to the base of the upper confining zone with a volume sufficient to prevent movement of fluids out of the injection zone through the wellbore and into the Lakota Sandstone;

    e. A plan to re-run a CBL to demonstrate adequate cement bond and isolation following the squeeze; and

    f. A plan to place cement retainers and plugs within the production casing comparable to those placed during the original P&A and sufficient to prevent fluid movement into or between USDWs.

2. Following completion of the corrective actions, the Permittee shall submit a report for EPA review, comment and approval. The report shall document the field activities, summarize any deviations from the approved plan, include a final well P&A diagram, and demonstrate to the satisfaction of the Director that the wellbore cannot act as a conduit for movement of fluids out of the approved injection zone.

3. Alternately, the Permittee may propose and implement another method of corrective action to demonstrate that the Brinkerhoff 3 wellbore will not act as a conduit for fluid movement out of the approved injection zone. Any such alternate proposal is subject to approval by the Director and may require modification of this Permit.

STATEMENT OF BASIS

Merit Energy Company
Brinkerhoff 3A
Wind River Indian Reservation

Class II Enhanced Oil Recovery Well
WY22427-12116

CONTACT: Chris Brown
U. S. Environmental Protection Agency
Underground Injection Control Program, 8WD-SDU
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: (303) 312-6669
Email: Brown.Christopher.T@epa.gov

This Statement of Basis gives the derivation of site-specific Underground Injection Control (UIC) permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in WY22427-12116 (Permit).

EPA UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water (USDWs). EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR parts 2, 124, 144, 146 and 147, and address potential impacts to USDWs. In accordance with 40 CFR § 144.35, issuance of this Permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property or invasion of other private rights, or any infringement of other federal, state or local laws or regulations. Under 40 CFR § 144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR parts 144, 146 and 147) are not discussed in this document. Regulations specific to Indian country injection wells in Wyoming are found at 40 CFR § 147.2553.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of injection well or wells so that the injection does not endanger USDWs. The Permit is issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR § 144.40 and can be modified or revoked and reissued under 40 CFR § 144.39 or § 144.41. The Permit is subject to EPA review at least once every five (5) years to determine if action is required under 40 CFR § 144.36(a).

The Permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to an approved state or tribal program, unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a tribal or state permit.

PART I. General Information and Description of Project

Merit Energy Company
13727 Noel Road, Suite 1200
Dallas, Texas 75240

hereinafter referred to as the "Permittee," submitted an application for a UIC Program permit for the following injection well or wells:

Brinkerhoff 3A
660' FEL & 330' FSL, Section9, T3N, R1W
Wind River Indian Reservation, Wyoming
49-013-06977

The application, including the required information and data necessary to issue or modify a UIC permit in accordance with 40 CFR parts 2, 124, 144, 146 and 147, was reviewed and determined by EPA to be complete.

Project Description

The Permittee is proposing to convert the existing Brinkerhoff 3A well from an oil and gas production well to a Class II Enhanced Oil Recovery (EOR) injection well. The Brinkerhoff 3A was drilled and completed with perforations in the Phosphoria Formation in 1966. Perforations in the Phosphoria Formation were subsequently isolated with a cast iron bridge plug (CIBP) set at 6,760 ft-KB and cement retainer set at 6,180 ft-KB. In 1983, perforations were added for oil production in the Crow Mountain Sandstone Member of Chugwater Formation (hereafter referred to as the Crow Mountain Sandstone). Oil production reportedly declined quickly due to low reservoir pressure and the well has been dormant since 1996. The Permittee intends to use the Brinkerhoff 3A well to provide a waterflood response to nearby production wells in the Crow Mountain Sandstone.

The conversion to a Class II EOR well would allow for the injection of Class II fluids for the purpose of enhanced recovery of oil or natural gas, as defined in 40 Code of Federal Regulations § 146.5. The Permittee has proposed a maximum daily injection rate of 2,500 barrels per day (bbl/d) and average daily injection rate of 1,000 bbl/d.

PART II. Permit Considerations (40 CFR § 146.24)

Geologic Setting

The Wind River Basin is located in the central portion of Wyoming and consists of more than 10,000 feet (ft.) of sedimentary rocks in the area of the Brinkerhoff 3A well. It is bounded to the north by the Absaroka and Owl Creek Mountains, to the east by the Casper Arch, to the south by the Granite Mountains, and to the west by the Wind River Mountains. The Brinkerhoff 3A well is located within the Steamboat Butte Field in the northwestern portion of the basin. Specifically, the Brinkerhoff 3A well is located on the southeastern portion of the Steamboat Butte Anticline.

The Steamboat Butte Anticline is one of several northwesterly striking en echelon, anticlinal structures in the region. These anticlinal structures are generally bound by basement cored, listric thrust faults dipping to the northeast and off-set by a series of basement bound shear zones. A major thrust fault associated with the Steamboat Butte anticline structure is located approximately 0.75 miles southwest of the Brinkerhoff 3A well. This thrust fault reportedly has 1,500 feet of displacement and serves as the primary structural trap for oil-bearing zones in the Steamboat Butte Field. This assertion is supported by the presence of dry holes west of the fault; specifically, no production associated with the Tribal 1 well is reported in the Wyoming Oil and Gas Conservation Commission (WOGCC) database. The strike of the thrust fault is North 25 degrees west with an interpreted dip ranging from 30 to 45 degrees to the northeast, and no wells is the Steamboat Butte Field reportedly penetrate the principal plane of the reverse fault (Blackstone, 1998). A normal fault is located approximately 0.5 miles west of the proposed injection well (Murphy and Roberts, 1954). This normal fault reportedly includes a north-northwest striking, 500 foot wide fault zone and dips 60-75 degrees west-southwest where it intersects the major regional thrust fault plane in the Mowry Shale. A secondary reverse fault was identified approximately 1,650 feet southwest of the Brinkerhoff 3A well. This fault strikes roughly northwest-to-southeast, and the mapped location depicts it as dying out outside of the 1/4-mile area of review (AOR).

The Crow Mountain Sandstone is believed to be of tidal flat or shallow marine origin (Tohill and Picard, 1966), and is considered a minor reservoir in the region (Kirschbaum et al, 2007). Oil in the Crow Mountain Sandstone was first produced in 1955, and a total of 353.9 million barrels (bbls) of oil and 492.7 million bbls of water have reportedly been produced from the Crow Mountain Sandstone. This production came from nine (9) wells, of which, only two (2) are still active. The reservoir has reportedly become unproductive with the gradual loss of reservoir pressure over time.

Table 2.1 provides a summary of formations and major stratigraphic units above and below the injection zone. Except as otherwise noted, all formation and stratigraphic unit depths are relative to the Brinkerhoff 3A well.

TABLE 2.1
Geologic Setting

Formation Name or Stratigraphic Unit	Top (ft-KB)*	Base (ft-KB)*	Median TDS (mg/L)	Lithology
Quaternary deposits	0	~200-400[1]	2,910[2]	Yellowish brown and gray, fine to very coarse sand with some greenish-gray shale and sandy shale[1].
Cody	~200-400[1]	3,005	4,884[3]	Gray to dark gray shales with interbedded grey fine to course sandstones.
Frontier	3,005	3,731	5,982	Laterally continuous light-gray to dark-gray sandstone and siltstone, interbedded with gray to black marine shale.
Mowry	3,731	4,248	--	Dark-brown to black fissile siliceous shales with numerous bentonite beds and local thin, fine-grained sandstones.
Muddy	4,248	4,306	8,370	Very fine to medium-grained sandstone interbedded with minor amounts of shale, siltstone and carbonaceous shale.
Thermopolis	4,306	4,466	--	Dark-gray to black shale, interbedded with thin layers of siltstone, sandy claystone, and bentonite.

Dakota	4,466	4,751	6,143	Fine-grained alluvial and deltaic quartz sandstones with abundant chert.
Lakota (Cloverly)	4,751	4,783		Fine- to coarse-grained fluvial sandstones that are locally pebbly or conglomeratic and contains abundant chert.
Morrison	4,783	4,967	--	Very-fine lenticular fluvial sandstones and siltstone encased in deep red/purple to green mottled shales.
Sundance	4,967	5,217	29,782[3]	Oolitic limestone, glauconitic sandstone with dispersed shale interbeds.
Gypsum Springs	5,217	5,323	--	Red siltstone and fine sandstones with interbedded red shales, gypsum and anhydrite nodules and interbeds.
Gypsum Springs Anhydrite	5,323	5,421	--	Massive anhydrite.
Nugget	5,421	5,539	26,454	Very-fine to fine grained eolian quartz sandstone.
Popo Agie (Chugwater Formation)	5,539	5,702	--	Deep red fluvial and lacustrine mudstones and carbonaceous siltstones.
Crow Mountain Sandstone (Chugwater Formation)	5,702	5,813	12,300	Fine to medium grained, marine shelf, silty sandstone, and red tidal siltstones.
Alcova Limestone (Chugwater Formation)	5,813	5,819	--	Thin dense limestone with abundant algal matting.
Red Peak Shale (Chugwater Formation)	5,819	6,650	--	Red silty claystones, siltstones and fine-grained sand lenses encased in nearshore and tidal shales/mudstones.
Dinwoody	6,650	6,756	--	Argillaceous dolomitic siltstones to silty dolomite.
Phosphoria	6,756	7,011[4]	13,023	Dolomite and dolomitic limestone interbedded with dolomitic siltstones and bioclastic carbonaceous shales.
Tensleep	7,011[4]	7,306[4]	2,806	Well sorted eolian quartz sandstone with interbeds of

				dolomite or dolomitic sandstone.
Amsden	7,306[4]	7,624[4]	--	Red to light greenish gray shale with white, fine grained, basal sandstone (Darwin Sandstone).
Madison	7,624[4]	--	3,279	Light gray to tan, dense to microcrystalline, dolomitic limestone with some vuggy and inter crystalline porosity.

* depths are approximate values at the wellbore relative to a Kelly Bushing (KB) of 10 ft.
[1] Based on gross thickness and lithologic description reported at the Tribal C-7 well.
[2] TDS concentration data supplemented from the USGS National Water Information System (NWIS) Database
[3] TDS concentration data supplemented from the USGS Produced Water Database v2.3
[4] Formation top estimated from the gross thickness encountered at the Tribal E-26 well.

Injection Zone

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zone is listed in TABLE 2.2.

Injection will occur into an injection zone that is separated from USDWs by confining zones which are free of known open faults or fractures within the AOR.

The Crow Mountain Sandstone at the Brinkerhoff 3A well is 111 feet thick and reportedly has a net permeable thickness of 45 feet with a V-shale less than 43%, an average porosity of 13.1%, and average permeability of 23.7 millidarcies (md). The Crow Mountain Sandstone consists of very fine to fine-grained silty sandstone with shale interbeds.

TABLE 2.2
INJECTION ZONE

Formation Name or Stratigraphic Unit	Top (ft-KB)*	Base (ft-KB)*	Porosity	Exemption Status
Crow Mountain Sandstone Member of the Chugwater Formation	5,702	5,813	13.1%	Not exempt

* depths are approximate values at the wellbore relative to a KB of 10 ft.

Confining Zones

A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above and below the injection zone. The confining zone or zones are listed in TABLE 2.3.

The Popo Agie Member of the Chugwater Formation is 163 feet thick and contains 106 feet of shale interbeds that provide confinement above the injection zone; sands within the Popo Agie are reportedly heavily cemented, as evidenced by the absence of porosity in open hole logs. Additional confinement in between the injection zone and the first identified USDW above the injection zone is provided by the anhydrite beds of the Gypsum Spring Formation, which is regionally extensive in the western portion of the Wind River Basin (Kirschbaum et al, 2007). The Alcova Limestone is a thin dense limestone, and the Red Peak Shale Member of the Chugwater

Formation is 831 feet thick with 56 feet of low permeability shale that provide confinement below the injection zone. Additional confinement below the injection zone is provided by interbedded shale layers in the lower portion of the Chugwater Formation.

TABLE 2.3
CONFINING ZONES

Formation Name or Stratigraphic Unit	Top (ft)	Base (ft)	Lithology
Popo Agie (Upper Confining)	5,539	5,702	Deep red fluvial and lacustrine mudstones and carbonaceous siltstones.
Alcova Limestone (Lower Confining)	5,813	5,819	Thin dense limestone with abundant algal matting.
Red Peak Shale (Lower Confining)	5,819	6,650	Red silty claystones, siltstones and fine-grained sand lenses encased in nearshore and tidal shales/mudstones.

* depths are approximate values at the wellbore

Underground Sources of Drinking Water (USDWs)
Aquifers, or the portions thereof, which 1) currently supply any public water system or 2) contains a sufficient quantity of groundwater to supply a public water system and currently supplies drinking water for human consumption or contain fewer than 10,000 milligrams per Liter (mg/L) total dissolved solids (TDS), are considered to be USDWs.

The nearest public water system (PWS) well is located approximately 6.5 miles west-southwest, and is associated with the Wyoming Department of Transportation, Diversion Dam rest area. According to records in the Wyoming State Engineer's Office e-permit database, this well is completed to a depth of 340 feet. All domestic water wells identified by the Permittee within a five (5)-mile radius of the Brinkerhoff 3A well are completed to depths less than 500 feet.

Water quality samples from the Crow Mountain Sandstone reported in the USGS Produced Water Database v2.3 exhibited TDS concentrations ranging from 9,101 mg/L to 41,433 mg/L. The Permittee has collected two (2) production water quality samples from the Brinkerhoff 4 well, currently producing from the Crow Mountain Sandstone. TDS concentrations of 8,367 in 2018 and 30,074 mg/L in 2021 were reported for the two (2) production water quality samples. However, these production water quality samples were reportedly collected after the well had been hydraulically fractured in 2018, and one or both of the samples may not be representative of the natural water quality of the Crow Mountain Sandstone. The reported range of TDS concentrations for the Crow Mountain Sandstone within the Steamboat Butte Field suggests that it may contain TDS concentrations less than 10,000 mg/L. The permit requires the collection of a representative formation sample from the injection zone prior to receiving authorization to inject to verify the TDS concentration of the Crow Mountain Sandstone at the Brinkerhoff 3A well. An aquifer exemption will be necessary if the formation sample collected from the proposed injection zone exhibits a TDS concentration less than 10,000 mg/L.

Six (6) formations exhibiting TDS concentrations less than 10,000 mg/L have been identified above the injection zone. Specifically, the Quaternary deposits, sandstones of the Cody Shale, Frontier Formation, Muddy Sandstone, Dakota Sandstone and Lakota Sandstone (also called the Cloverly Formation) are all considered USDWs. The Sundance Formation and Nugget Sandstone are not considered USDWs because available water quality sample results not comingled with other formations in the Steamboat Butte and Pilot Butte Fields indicate TDS concentrations greater than 10,000 mg/L.

Four (4) formations exhibiting TDS concentrations less than 10,000 mg/L have been identified below the injection zone. Specifically, the Phosphoria Formation, Tensleep Formation, Darwin Sandstone member of the Amsden Formation, and Madison Limestone are all considered USDWs. However, the portions of the Phosphoria and Tensleep Formations on the west half of Section 9, Township 3 North, Range 1 West are not considered USDWs because they are part of an area aquifer exemption described in 40 CFR § 147.2554 for the Steamboat Butte Field.

Table 2.4 provides a summary of information regarding known or estimated TDS concentrations above, below, and within the injection zone and provided in the permit application or otherwise identified by EPA. Unless otherwise noted in the table, TDS concentration data was derived from sample results report in the United States Geologic Survey (USGS) Produced Water Database v2.3 for the Steamboat Butte and Pilot Butte Fields.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDWs)

Formation Name or Stratigraphic Unit	Top (ft-KB)*	Base (ft-KB)*	Max. (mg/L)	Median (mg/L)	Min. (mg/L)	# of Samples
Quaternary deposits[2]	0	~200-400[1]	6,880	2,910	1,100	4
Cody[3]	~200-400[1]	3,005	14,180	4,884	2,219	30
Frontier	3,005	3,731	11,536	5,982	3,841	17
Muddy	4,248	4,306	10,370	8,370	4,589	10
Dakota	4,466	4,751	8,347	6,143	4,543	4
Lakota (Cloverly)	4,751	4,783				
Crow Mountain Sandstone (Chugwater Formation)	5,702	5,813	41,433	12,300	9,101	7
Phosphoria	6,756	7,011[4]	31,429	13,023	2,500	67
Tensleep	7,011[4]	7,306[4]	23,665	2,806	1,828	72
Amsden (Darwin Sandstone member)	7,306[4]	7,624[4]	6,100	--	6,100	1
Madison	7,624[4]	--	10,316	3,279	1,960	6

* depths are approximate values at the wellbore relative to a KB of 10 ft.
[1] Based on gross thickness and lithologic description reported at the Tribal C-7 well.
[2] TDS concentration data supplemented from the USGS National Water Information System (NWIS) Database
[3] TDS concentration data supplemented from the USGS Produced Water Database v2.3
[4] Formation top estimated from the gross thickness encountered at the Tribal E-26 well.

References:

Blackstone, Jr., D. L., 1998. Faulting in Steamboat Butte and Pilot Butte anticlines, west-central Wyoming: a review. Contributions to Geology, University of Wyoming, v. 32, no. 2, p. 159-180.

Kirschbaum, M.A., Lillis, P.G., and Roberts, L.N.R., 2007, Geologic assessment of undiscovered oil and gas resources in the Phosphoria Total Petroleum System of the Wind River Basin Province, Wyoming, in USGS Wind River Basin Province assessment team, Petroleum systems and geologic assessment of oil and gas in the Wind River Basin Province, Wyoming: U.S. Geological Survey Digital Data Series DDS–69–J, ch. 3, 27 p.

Murphy, J.F., and Roberts, R.W., 1954. Geology of the Steamboat Butte-Pilot Butte Area, Freemont

County, Wyoming: U.S. Geologic Survey Oil and Gas Investigation. Map OM 151.

Tohill, Bruce, and Picard, M.D., 1966. Stratigraphy and petrology of Crow Mountain Sandstone Member (Triassic), Chugwater Formation, northwestern Wyoming: American Association of Petroleum Geologists Bulletin, v. 50, no. 12, p. 2547-2565.

PART III. Well Construction (40 CFR § 146.22)

The approved well construction plan, incorporated into the Permit as APPENDIX A, will be binding on the Permittee. Modification of the approved plan during construction is allowed under 40 CFR § 144.52(a)(1) provided written approval is obtained from the Director prior to actual modification.

Casing and Cement
The well construction plan was evaluated, and two (2) conditions were incorporated into APPENDIX A to ensure the well is cased and cemented to prevent the movement of fluids into or between USDWs in accordance with 40 CFR § 146.22. These conditions must be fulfilled prior to receiving authorization to inject. Specifically, the existing cast iron bridge plug set at 6,760 ft-KB and topped with eight (8) ft. of cement must have a minimum 20-foot cement plug as described in Guidance No. 40: Plugging and Abandonment Requirements for Class II Injection Wells.

Additionally, existing cement behind the 5-1/2" production casing of the Brinkerhoff 3A does not provide for isolation to prevent the movement of fluid into or between USDWs. Specifically, the Nugget Sandstone and Sundance Formation with TDS concentrations greater than 10,000 mg/L are not isolated from overlying USDWs below the surface casing and identified in table 2.4. Consequently, APPENDIX A requires that the permittee develop and subsequently implement a plan to isolate the Nugget Sandstone and Sundance Formation from overlying USDWs. Alternatively, APPENDIX A provides that the Permittee may demonstrate that fluid movement is not occuring into or between USDWs by planning and performing a noise log following guidance available in the July 1994, EPA/600/R-94-124 publications titled "Temperature, Radioactive Tracer, and Noise Logging for Injection Well Integrity". For this alternative to be an acceptable substitute, the results and analysis of the noise log must demonstrate that fluid movement is not occuring into or between USDWs behind the 5-1/2" production casing.

Well construction details for the injection well(s) are shown in TABLE 3.1. Remedial cementing may be required if the casing cement is shown to be inadequate by cement bond log or other demonstration of external (Part II) mechanical integrity.

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft-KB)	Cemented Interval (ft-KB)
Surface	13-3/4"	8-5/8"	0-509	0-509
Production	7-7/8"	5-1/2"	0-6,939	5,514-6,939
Tubing	--	2-7/8"	0-5,707	--

Injection Tubing and Packer
Injection tubing is required to be installed from a packer up to the surface inside the well casing. The packer will be set within 100 feet above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the production casing.

Tubing-Casing Annulus
The tubing-casing annulus (TCA) allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity and will allow for detection of leaks. The TCA will be filled with non-corrosive fluid or other fluid approved by the Director.

Sampling and Monitoring Device
To fulfill Permit monitoring requirements and provide access for EPA inspections, sampling and monitoring equipment will need to be installed and maintained. Required equipment includes but is not limited to: 1) pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure (MAIP) is reached at the wellhead; 2) fittings or pressure gauges attached to the injection tubing(s), TCA, and surface casing-production casing (bradenhead) annulus; 3) a fluid sampling point between the pump house or storage tanks and the injection well, isolated by shut-off valves, for sampling the injected fluid; and 4) a flow meter capable of recording instantaneous flow rate and cumulative volume attached to the injection line.

All sampling and measurement taken for monitoring must be representative of the monitored activity.

PART IV. Area of Review, Corrective Action Plan (40 CFR § 144.55)

Area of Review
Permit applicants are required to identify the location of all known wells within the AOR which penetrate the injection zone. Under 40 CFR § 146.6 the AOR may be a fixed radius of not less than one quarter (1/4) mile or a calculated zone of endangering influence. For area permits, a fixed width of not less than one quarter (1/4) mile for the circumscribing area may be used.

The AOR for the Brinkerhoff 3A well is a fixed radius of one-quarter (1/4) mile. There are two (2) wells that penetrate the injection zone within the 1/4 mile AOR listed in Table 4.1. These wells include one (1) production well and one (1) plugged and abandoned (P&A'd) production well.

TABLE 4.1

AOR Well Name	API	Well Type	Operating Status	Total Depth (ft-KB)	Distance (ft) /Direction from Brinkerhoff 3A[1]
Brinkerhoff 3	49-013-06367	Production	Plugged and Abandoned	7,076	749 N-NW
Brinkerhoff 4	49-013-06463	Production	Producing	6,696	1,290 W-NW

Notes: [1] Approximate distance to the nearest of the surface or bottom hole locations

Based on a review of well construction information submitted with the permit application, the Brinkerhoff 3 well exhibits conditions warranting corrective action. Potential conduits for injection of fluids out of the authorized injection zone were not identified in a review of the construction records for the Brinkerhoff 4 well.

Corrective Action Plan (CAP)
For wells in the AOR which are improperly sealed, completed or abandoned, the applicant will develop a CAP consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

TABLE 4.1 lists the wells in the AOR and shows the well type, operating status, depth and distance/direction from the Brinkerhoff 3A well. Based on a review of well records for the Brinkerhoff 3 well, a CAP is required as a condition prior to receiving authorization to inject into the Brinkerhoff 3A well.

The CAP will be incorporated into the Permit as APPENDIX F and becomes binding on the Permittee.

TABLE 4.2
CAP TABLE

AOR Well Name	Well Type	Operatin g Status	Total Depth (ft-KB)	Corrective Action(s)
Brinkerhoff 3	Production	P&A'd	7,076	Described Appendix F

A summary of the reported well records for the Brinkerhoff 3 well is presented in the section below:

Brinkerhoff 3:
The Brinkerhoff 3 well was drilled in 1948 and completed to a total depth of 7,076 ft. Well completion records indicate that the 7-inch production casing was cemented with two (2) cement stages. The first stage was at 7,069 ft. with 300 sacks of cement, and the second stage was at 4,708 ft. by a D.V tool with 400 sacks of cement. No top of cement was specifically reported; however, a calculation based on the volume of cement assuming a 25% loss resulted in an estimated top of cement for the first stage of 5,622 and an estimated top of cement for the second stage of 2,778 ft. The well was subsequently P&A'd in 1966 after a remedial work-over failed to repair the 7-inch casing and fish out tubing/rods that had become stuck in the well. Specifically, a hole was reported at 5,628 ft. where the 7-inch casing parted. During the remedial work-over, the well was swaged from 5,616 to 5,663 with the top of stuck tubing at 5,600 ft. The pipe swage reportedly went out of the 7-inch casing at 5,628 ft. and was driven into the formation through a tight hole to 5,663 ft., which corresponds to the top of the Crow Mountain Sandstone. Additionally, the fact that the swage was reportedly driven outside of the casing suggests that the top of cement for the first stage may actually be less than the estimated 5,622 ft. The well was subsequently plugged and abandoned with a 40 sack cement plug placed from 5,411 to 5,663 ft, a 20 sack plug placed from 4,480 to 4,600 ft., and a five (5) sack plug placed from 0 to 31 ft.

Based on a review of the well records for the Brinkerhoff 3 well, a conduit for fluid movement at the top of the Crow Mountain Sandstone up to at least 5,628 ft was reportedly created during the 1966 remedial work-over. This depth is within six (6) feet of the estimated top of cement behind the 7-inch casing. A six (6) foot interval of cement behind the 7-inch casing is not sufficient to demonstrate isolation above the Crow Mountain Sandstone, and there is some evidence that no cement may be present above the top of the Crow Mountain Sandstone. Swaging involves physically driving a wedge-shaped tool designed to force its way through a casing or tubing restriction. The integrity of any cement, if present, would likely have been compromised by the swaging activities occuring between 5,616 and 5,663 ft.

The next cemented interval above the Crow Mountain Sandstone behind the 7-inch production casing occurs at 4,708 ft. This depth is 75 ft. above the base of the Lakota Sandstone, which has been identified as a USDW. P&A records following the failed 1966 remedial work-over indicate that no cement barrier was placed behind the uncemented or compromised 7-inch casing interval occuring in between the Crow Mountain Sandstone and the Lakota Sandstone. Consequently, there is an apparent uncemented conduit and compromised casing associated with the 7-inch production casing of the Brinkerhoff 3 well that may cause fluid movement into a USDW if corrective action is not taken prior to injection into the Brinkerhoff 3A well. As a result, and pursuant to 40 CFR § 144.55, a corrective action plan will be incorporated into APPENDIX F of the Permit and must be completed prior to receiving authorization for injection into the Brinkerhoff 3A well. The purpose of the corrective action plan is to assess the existing wellbore conditions and subsequently isolate the Crow Mountain Sandstone from the Lakota Sandstone at the Brinkerhoff 3 well.

Table 4.3 provides a summary of the intervals of uncemented or compromised casing relative to the injection zone and upper confining zone at the Brinkerhoff 3 well.

TABLE 4.3

Well Name	Upper Confining Zone	Injection Zone	Uncemented Interval Behind Production Casing	Interval of Compromised Production Casing
Brinkerhoff 3	5,506-5,663 ft.	5,663-5,789 ft.	4,708 to 5,622 ft.	5,616-5,663 ft.

*Depths are measured depths (MD) relative to the wellbore.

PART V. Well Operation Requirements (40 CFR § 146.23)

Mechanical Integrity (40 CFR § 146.8)
An injection well has mechanical integrity (MI) if:

1. Internal (Part I) MI: there is no significant leak in the casing, tubing, or packer; and
2. External (Part II) MI: there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore.

The Permit requires MI to be maintained at all times. The Permittee must demonstrate MI prior to injection and periodically thereafter, as required in APPENDIX B Logging and Testing Requirements. A demonstration of well MI includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating internal (Part I) and external (Part II) MI are dependent upon well and are subject to change. Should well conditions change during the operating life of the well, additional requirements may be specified and will be incorporated as minor modifications to the Permit.

A successful internal Part I Mechanical Integrity Test (MIT) is required prior to receiving authorization to inject and repeated no less than five years after the last successful MIT. A demonstration of internal MI is also required following any workover operation that affects the tubing, packer, or casing or after a loss of MI. In such cases, the Permittee must complete work and restore MI within 90 days following the workover or within the timeframe of the approved alternative schedule. After the well has lost mechanical integrity, injection may not recommence until after internal MI has been demonstrated and the Director has provided written approval.

Internal (Part I) MI is demonstrated by using the maximum permitted injection pressure or 1,000 psi, whichever is less, with a ten percent or less pressure loss over thirty minutes. Additional guidance for Internal (Part I) MI can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

External (Part II) MIT may be demonstrated by evaluation of a temperature survey. Guidance on temperature logging for mechanical integrity can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

A demonstration of External Part II MI is required prior to receiving authorization to inject. Since the Brinkerhoff 3A well was reportedly facture stimulated in 1983 during the recompletion of the well in the Crow Mountain Sandstone and after the original CBL was run in 1966, the Part II MIT demonstration prior to receiving authorization to inject consists of a temperature survey. Although not considered a Part II MIT in this instance pursuant to Federal Register Notice Volume 52, No. 181, September 18, 1987 (subsequently revised December 10, 1987), a radioactive tracer survey is also required prior to receiving authorization to inject. The radioactive tracer survey will include an injectivity profile and channel check(s) to show which perforations in the injection zone(s) are taking the injected fluid and to demonstrate that no fluid is channeling in cement behind the production casing above or below the approved injection zone. These requirements are found in APPENDIX B Logging and Testing Requirements of the Permit.

Injection Fluid Limitation
Injected fluids are limited to those used for enhanced recovery of oil or natural gas, as defined in 40 CFR § 144.6(b)(2). This Permit does not allow for the injection of any hazardous waste as defined in 40 CFR 261.3. Injection of any substance defined as a hazardous waste, whether hazardous by listing or characteristic, is a violation of this permit and requires notification under Part III, Section D.11. This well is not approved for commercial brine injection or injection of fluids defined in 40 CFR § 144.6(b)(1) for the purpose of fluid disposal.

Prior to adding a new source, a fluid analysis sample must be provided for any new source that was not previously characterized. A new source may include fluids from different production formation, well field, or that are chemically dissimilar from fluids that are already injecting into the well. The list of analytes is found in APPENDIX D of the Permit "WITH THE FIRST ANNUAL REPORT AFTER RECEIVING AUTHORIZATION TO INJECT AND PRIOR TO INTRODUCTION OF A NEW SOURCE". The MAIP may need to be recalculated as a result of the new sample analysis.

Volume Limitation
As indicated in APPENDIX C of the Permit, there is no limitation on the fluid volume permitted to be injected into this well. In no case shall injection pressure exceed the MAIP.

If an aquifer exemption is required and approved for this Permit, then a volume limit will be set based on the conditions of the aquifer exemption, through the modification process.

Injection Pressure Limitation
40 CFR § 146.23(a)(1) requires that the injection pressure at the wellhead must not exceed a maximum calculated to ensure that the pressure during injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs. In lieu of testing the fracture pressure of the confining zone, which may be impractical, the pressure in the injection formation provides a conservative surrogate.

The calculated MAIP described below is the pressure that will initiate fractures in the injection zone and that the Director has determined satisfies the above condition.

Except during stimulation, the injection pressure must not exceed the MAIP. Furthermore, under no circumstances shall injection pressure cause the movement of injection or formation fluids into a USDW.

The **MAIP** allowed under the permit, as measured at the surface, will be calculated according to the equations below. The Permit itself does not contain a specific MAIP value but instead requires that a MAIP be calculated using these equations. The Permit also specifies where the input values are derived from. Prior to authorization to commence injection, the Permittee must submit for review the necessary information to calculate the MAIP. After review of the submitted documents, the Director will notify the Permittee of the MAIP in the written authorization to commence injection.

The formation fracture pressure (**FP**) is the pressure above which injection of fluids will cause the rock formation to fracture. This equation, as measured at the surface, is defined as:

$$\mathbf{FP} = [\mathbf{FG} - (0.433 * (\mathbf{SG} + 0.05))] * \mathbf{D}$$

Where, FG is the fracture gradient in psi/ft
SG is the specific gravity
D is the depth of the top perforation in feet

The **FG** value for each well will be determined by conducting a step rate test. The results of the test will be reviewed and approved by the Director. As appropriate, the FG may be determined by one of these other following methods:

- Representative **FG** values determined previously from valid tests in nearby wells.

- Established **FG** values found in reliable sources approved by the Director. These could include journal articles, scientific studies, etc.
- An alternative method approved by the Director.

The value for **SG** must be obtained from the fluid analysis of a representative sample of the injection fluid.

The value for **D** is the depth of the top perforation of the as-built well.

When a step rate test is conducted, bottom-hole and surface gauges are required. This requirement may be waived by the Director but may result in a final MAIP that does not include adjustment for friction loss.

The MAIP can also be adjusted for friction loss if the friction loss can be adequately demonstrated. To account for friction loss, the **MAIP** is equal to **FP** adjusted for friction loss, or:

MAIP = **FP** + friction loss (if applicable)

An acceptable method to determine friction loss is to measure it directly. Friction can be calculated when surface and bottom-hole pressures are known. When conducting a step rate test, a surface and bottom-hole gauge at depth **D** are necessary to calculate friction loss.

During the operational life of the well, the depth to the top perforation, fracture gradient, and specific gravity may change. When well workover records, tests, or monitoring reports indicate one of the variables in the FP equation has changed, the MAIP calculation will be reviewed. EPA is incorporating the MAIP equations into this Permit instead of identifying a specific MAIP value because it will result in a more efficient application of the true MAIP, as these changes occur over the life of the well to provide greater protection for nearby USDWs.

When additional perforations to the injection zone are added, the Permittee must provide the appropriate workover records and also demonstrate that the fracture gradient value to be used is representative of the portion of the injection interval proposed for perforation. It may be necessary to run a step rate test to provide representative data, such as when a new formation (within the approved injection zone) or a geologically distinct interval (based on core data or well logs) in the same formation is proposed for injection.

When the fracture gradient or depth to top perforation changes, the formation fracture pressure will be recalculated. The Permittee will also submit fluid analysis that reports SG annually. In the above, a factor of 0.05 has been added to the SG. This adjustment factor allows for the MAIP to be recalculated only if the newly submitted SG is greater than 0.05 from the previous year's SG, without exceeding the fracture pressure of the formation. A MAIP due to the SG change will only be recalculated if the absolute difference of the newly submitted SG and that of the previous year is greater than 0.05.

The new permitted MAIP will become effective when the Director has provided written notification. The Permittee may also request a change to the MAIP by submitting the necessary documentation to support a recalculation of the MAIP.

As discussed above, the formation fracture pressure calculation sets the MAIP to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the confining zones adjacent to the USDWs. However, it may be that the condition of the well may also limit the permitted MAIP. When external (Part II) MIT demonstrations (such as a temperature survey or radioactive tracer test) are required, the tests required to make this demonstration must be conducted at the permitted MAIP based on the calculations described above. If during testing, the Permittee is unable to achieve the pressure at the permitted MAIP, the new permitted MAIP will be set at the highest pressure achieved during a successful external (Part II) MIT and not the calculated MAIP.

TABLE 5.1 provides an estimated formation fracture pressure based on the information submitted with the application. The permitted MAIP will be recalculated with the information submitted to obtain the authorization to commence injection.

TABLE 5.1
Injection Zone Fracture Pressure

Formation Name or Stratigraphic Unit	Depth (ft-KB)	Specific Gravity*	Fracture Gradient (psi/ft)	Friction Loss (psi)	Estimated Formation FP (psi)
Crow Mountain Sandstone	5,802	1.057	0.564[1]	N/A	620

**From the MAIP equation on page 12, SG+0.05 or 1.057*

[1] Frac gradient proposed by applicant based on an Instantaneous Shut-in Pressure (ISIP) recorded following a fracture stimulation of the Crow Mountain Sandstone at the Brinkerhoff 4 well with a factor of safety applied.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program
At least once a year the Permittee must analyze a sample of the injected fluid for parameters specified in APPENDIX D of the Permit. This analysis must be reported to EPA annually as part of the Annual Report to the Director. Any time a new source is added, a fluid analysis must be provided of the injection fluid that includes the new source as discussed above, in PART V Injection Fluid Limitation.

Instantaneous injection pressure, injection flow rate, injection volume, cumulative fluid volume, bradenhead and TCA pressures must be observed on a weekly basis. A recording, at least monthly, must be made of that month's injected volume and cumulative fluid volume to date, the maximum and average value for injection tubing pressure and rate, maximum and minimum annulus and bradenhead pressures. This information is required to be reported annually as part of the Annual Report to the Director.

PART VII. Plugging and Abandonment Requirements (40 CFR § 146.10)

Plugging and Abandonment Plan
Prior to abandonment, the well must be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable federal, state or local law or regulation. Tubing, packer and other downhole apparatus must be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement must be verified by tagging.

Within thirty (30) days after plugging the owner or operator must submit Plugging Record (EPA Form 7520-19) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment (P&A) plan is described in APPENDIX E of the Permit. The P&A Plan includes two (2) additional plugs beyond those proposed by the Permittee in the application. Plug #2 is required to isolate formations containing USDWs from the Sundance Formation and Nugget Sandstone, which are not USDWs and contain greater than 10,000 mg/L TDS. Plug #4 is required to isolate Quarternary deposits containing TDS concentrations < 3,000 mg/L TDS from deeper USDWs containing TDS concentrations between 3,000 mg/L and 10,000 mg/L TDS.

PART VIII. Financial Responsibility (40 CFR § 144.52(a)(7))

Demonstration of Financial Responsibility
The Permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The Permittee will show evidence of such financial responsibility to the Director by the submission of completed original versions of one of the following:

(a) a surety bond with a standby trust agreement,
(b) a letter of credit with a standby trust agreement,
(c) a fully funded trust agreement, OR
(d) a financial test and corporate guarantee.

The Director may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility, if necessary. The Permittee, may also upon written request provide an alternative demonstration of financial responsibility.

If a financial test is provided, evidence of continuing financial responsibility is required to be submitted to the Director annually.

PART IX. Considerations Under Other Federal Law (40 CFR § 144.4)

EPA will ensure that issuance of this Permit will be in compliance with the laws, regulations, and orders described at 40 CFR § 144.4, including the National Historic Preservation Act, the Endangered Species Act, and Executive Order 12989 (Environmental Justice), before a final permit decision is made.

National Historic Preservation Act (NHPA)
Section 106 of the National Historic Preservation Act, 54 U.S.C. § 306108, requires federal agencies to consider the effects on historic properties of actions they authorize, fund or carry out. EPA has determined that a decision to issue a Class II injection well permit for authorization of injection into the Brinkerhoff 3A well constitutes an undertaking subject to the National Historic Preservation Act and its implementing regulations at 36 CFR part 800.

The Brinkerhoff 3A well was drilled in 1966 and currently exists as a production well within the Steamboat Butte Field. This Permit will authorize the conversion of the Brinkerhoff 3A well from a production well to a Class II EOR injection well. No new surface-disturbing activity is required for such a conversion of an existing production well, nor is any such new surface-disturbing activity authorized by this Permit. Authorization from the U.S. Bureau of Land Management (BLM) would be required for any future activities involving surface disturbance at the location of the Brinkerhoff 3A well.

Based on this information, EPA is proposing to find that no historic properties will be affected as a result of issuing this UIC Permit.

Endangered Species Act (ESA)
Section 7(a)(2) of the Endangered Species Act (ESA), 16 U.S.C. § 1536 (a)(2), requires federal agencies to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally-listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. EPA has determined that a decision to issue a Class II permit for authorization of injection into the Brinkerhoff 3A well would constitute an action that is subject to the Endangered Species Act and its implementing regulations (50 CFR part 402). Accordingly, EPA will comply with these regulations by

determining what, if any, effects this action will have on any federally-listed endangered or threatened species or their designated critical habitat and by following any required ESA procedures. EPA's determination will be documented as part of the administrative record supporting this decision.

The Brinkerhoff 3A well was drilled in 1966 and currently exists as a production well within the Steamboat Butte Field. This Permit will authorize the conversion of the Brinkerhoff 3A well from a production well to a Class II EOR injection well. No new surface-disturbing activity is required for such a conversion of an existing production well, nor is any such new surface-disturbing activity authorized by this Permit. Authorization from the BLM would be required for any future activities involving surface disturbance at the location of the Brinkerhoff 3A well. In addition, the Brinkerhoff 3A well is not located within an area mapped as critical habitat for threatened and endangered species in the United States Fish and Wildlife Service (USFWS) Environmental Conservation Online System (ECOS).

Based on this information and the nature of the proposed conversion, EPA is proposing a no effect finding for the issuance of this UIC Permit.

Executive Order 12898

On February 11, 1994, the President issued Executive Order 12898, entitled "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations." EPA has concluded that the specific conditions of UIC Permit WY22427-12116 will prevent contamination to USDWs, including USDWs which either are or will be used in the future by communities of environmental justice (EJ) concern. These USDWs could include the aquifer within the proposed injection zone in which case injection would only commence if the aquifer is exempted and thereby no longer protected under the SDWA. The UIC program will be conducting enhanced public outreach to EJ communities by publishing a public notice announcement in local newspapers and holding a public hearing, if requested, or if public interest in the proposed permit is high.

Public Notice: Merit Energy Company, Brinkerhoff 3A Draft Permit, Wind River Indian Reservation, Wyoming, Permit No. WY22427-12116

How to Comment

Comments accepted through: 01/27/2022

You may comment on the proposed action using email or phone. **Due to office closures related to the COVID-19 outbreak, at this time please do not submit comments via regular mail.**

Submit comments to:

Chris Brown

Brown.Christopher.T@epa.gov

(800) 227-8917, extension 312-6669 or (303) 312-6669

Summary

Project Background Information: Merit Energy Company has submitted an application to convert the existing Brinkerhoff 3A well from a production well to a Class II Enhanced Oil Recovery (EOR) well. The Brinkerhoff 3A well is located in the Steamboat Butte Field within the exterior boundaries of the Wind River Indian Reservation. A UIC permit would allow injection for the purpose of enhanced recovery of oil or natural gas into the Crow Mountain Sandstone of the Chugwater Formation.

Proposed Action: EPA proposes issuance of UIC permit WY22427-12116 for the conversion of the Brinkerhoff 3A well from a production well to a Class II Enhanced Oil Recovery well.

Notification of any extension of the public comment period will appear at this web address. Alternatively, the public may contact Chris Brown by email at Brown.Christopher.T@epa.gov, or by phone at (800) 227-8917, extension 312-6669 or (303) 312-6669, to obtain information about these proposed actions or to be added to the notification list for any extension of the public comment period and any final EPA decision. Due to the current COVID -19 pandemic e-mail correspondence is preferred.

Applicant or Respondent

Merit Energy Company
13727 Noel Road, Suite 1200
Dallas, Texas 75240

Permit #: WY22427-12116

Public Notice Announcement for EPA UIC Permit Action

The U.S. Environmental Protection Agency intends to propose an Underground Injection Control (UIC) permit action, under the authority of the Safe Drinking Water Act and UIC program regulations, for the Brinkerhoff 3A well operated by Merit Energy Company. The Brinkerhoff 3A well is located within Section 9 of Township 3 North and Range 1 West of the Steamboat Butte Field and within the exterior boundaries of the Wind River Indian Reservation. An action to issue a permit would authorize the conversion of the existing Brinkerhoff 3A well from a production well to a Class II Enhanced Oil Recovery well. The public notice is forthcoming and will be posted at EPA Region 8 UIC program's website: https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy. The public will have 30 days from the start of the public notice to provide comments on the proposed permit action. Notification of any extension of the public comment period will appear at the web address only and will not appear in this newspaper. Alternatively, the public may contact or call Chris Brown at brown.christopher.t@epa.gov or 303-312-6669 to be notified of the public notice start date and/or request a copy of the public notice and documents associated with the proposed action.